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Energy Alberta 1985

Energy Resources Conservation Board
Review of Alberta Energy Resources in 1985

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ERCB

Oil, gas, oil sands, coal and hydro — Alberta has large reserves of the world's most commonly-used energy resources. Exploring, developing and selling these resources is the province's single biggest industry; providing thousands of jobs, billions of dollars to Alberta's economy and substantial revenues to the Alberta Government.

Energy Alberta is an annual review of energy developments in the province. It is published by the Energy Resources Conservation Board (ERCB). This issue provides a summary of important developments and statistics for 1985 and a brief explanation of the work of the ERCB.

A colour-coding system is used throughout this report to identify the various energy resources. The colour bars below will serve to guide the reader to information regarding each energy resource:

Oil

Gas

Oil Sands

Coal

Hydro

LUFKIN
LUFKIN
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LUFKIN
KIN

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Metric-Imperial Energy Equivalents

Oil
1 cubic metre = 6.3 barrels = approx. 0.83 tonnes

Natural Gas
1 cubic metre = 35.5 cubic feet

Coal
1 tonne = 0.984 long ton (2,240 pounds)

Distance
1 kilometre = 0.621 miles

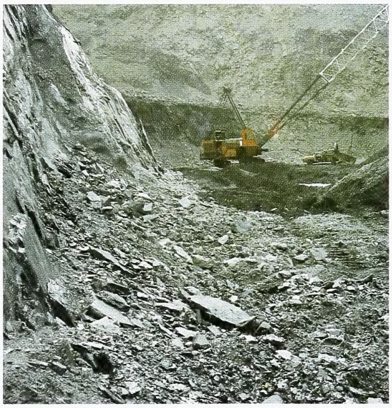
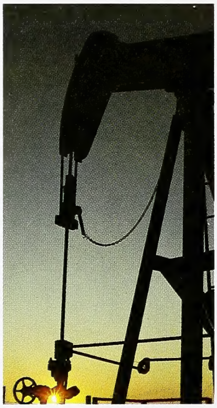
Energy
1 petajoule = energy equivalent of 164,000 barrels of crude oil
1 petajoule = energy equivalent of 1 billion cubic feet of gas

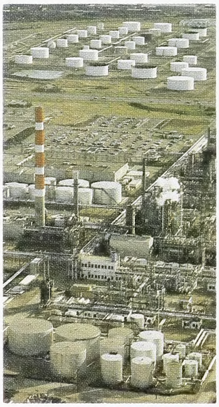
Enerfax

...nuggets of information from the Alberta energy lode

It isn't just energy that is generated from the province's energy resources: so are many little-known facts and figures.

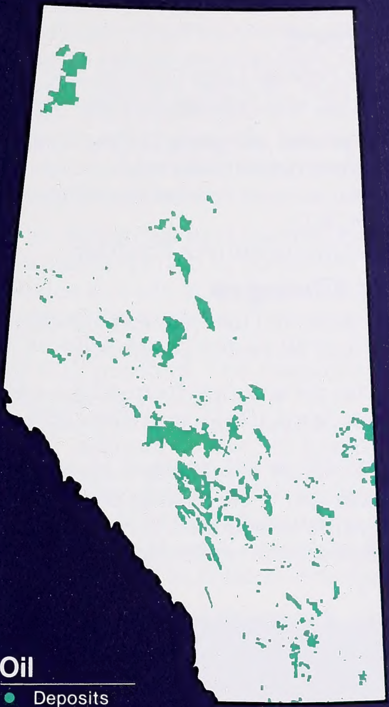
- MORE than 110,000 kilometres (69,000 miles) of seismic lines were shot in Alberta in 1985 — enough to go around the world 2 1/2 times
- ALBERTA produces more than half Canada's petrochemicals
- MORE than 109,000 wells have been drilled in Alberta; on average, that's one every 2 1/4 square miles
- LAID end-to-end, core samples from Alberta oil and gas wells, held by the ERCB Core Research Centre, would stretch 1,150 kilometres (720 miles)
- 440 drilling rigs were active in the province in 1985
- SALES of Crown mineral rights in Alberta reached $795 million in 1985 — third highest in history. (The record was set at $977 million in 1979)
- ALBERTA'S reserves of thermal coal are sufficient to keep the province's six existing coal-fired electric power plants supplied for 1,100 years; a typical power plant has a life-span of 35 years
- SYNCRUDE's four draglines and SUNCOR's three bucket wheels, near Fort McMurray, move 250,000 tonnes of oil sand every day
- ONE-THIRD of Alberta's $58 billion gross domestic product, in 1985, came from oil and gas operations
- 250,000 of Alberta's 1,100,000 jobs come from the oil and gas industry; 18,000 new jobs were made available in 1985, alone
- It takes 21 days for a barrel of oil to travel by pipeline from Edmonton to Toronto
- 70% of oil sands development expenditures are made here in Alberta



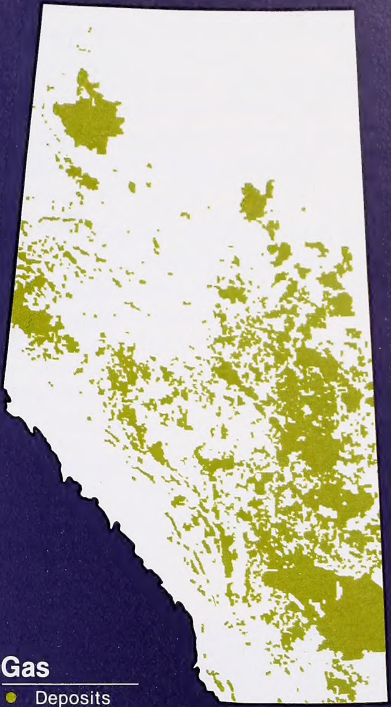
Alberta's Resources

...where they have been found to date



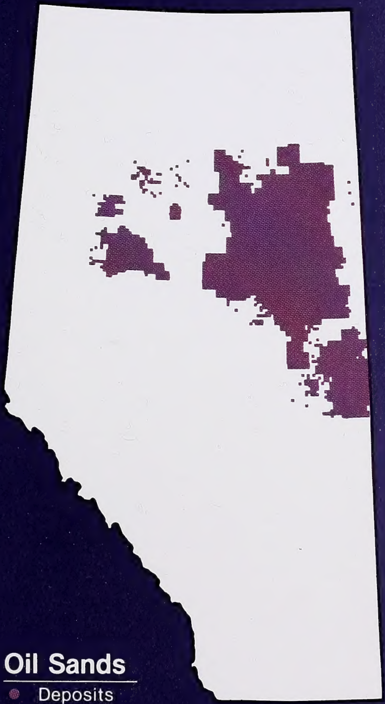
Oil

● Deposits



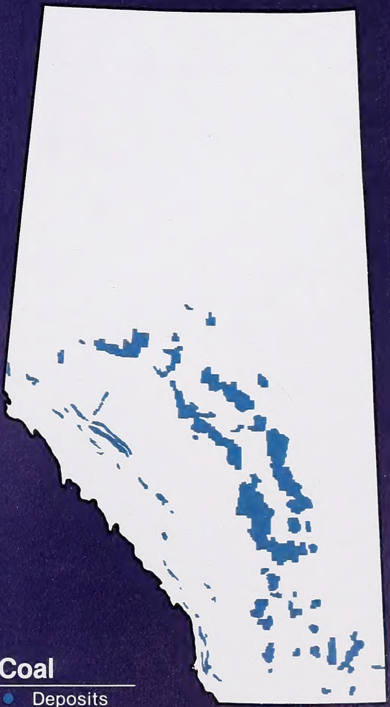
Gas

● Deposits



Oil Sands

● Deposits



Coal

● Deposits

Important Events of 1985

...the changing world of Alberta energy

Events in 1985 were dominated by agreements between the Federal and Provincial Governments. Although these agreements had some immediate effects, many of their provisions will take some time to reach full impact.

The Western Accord

On March 28, 1985 the Federal Government and the governments of Alberta, British Columbia and Saskatchewan agreed to:

- deregulate crude oil prices, allowing prices to rise to world oil levels and ending 12 years of government controls,
- eliminate or phase out several federal taxes, including the Petroleum and Gas Revenue Tax (PGRT),
- eliminate the Petroleum Incentives Program.

Alberta Royalty Changes

On June 12, 1985 the Alberta Government announced the following changes to its royalty and incentive programs:

- reduction in marginal royalty rate from 45% to 40% on old oil production (oil discovered before April 1984), and from 35% to 30% on new oil production, to be phased in over 24 months,
- Royalty Tax Credit to small producers increased to 75% of royalty payments, to a maximum of $3 million per company,
- new incentive programs introduced to reward oil and gas drilling success with royalty-free allowances; replacing various grants that tended to favour mere activity.

The Natural Gas Agreement

On October 31, 1985 the Federal Government and the Alberta, British Columbia and Saskatchewan governments agreed on a new basis for pricing and marketing natural gas produced in Western Canada. The main features of this agreement were:

- domestic gas prices deregulated (after a 12-month transition period),
- amendments to policies and tests for exports of natural gas, to provide freer access to export markets,
- elimination of the Alberta export flowback system after November 1, 1986.

The full effect of all these changes, without regard to other unrelated pricing changes, would be to increase annual cash flow to the Alberta energy industry by some $2-3 billion.

The deregulation of oil prices by the Western Accord ended 12 years of government price controls and allowed all crude oil prices to rise to world levels as compared to only the so-called "new oil" under the old regulated system. The average price of Alberta oil increased by some $13 per cubic metre ($2 per barrel) with deregulation, and prices are now generally tracking world oil prices.

Deregulation of oil prices has also raised concerns and divided industry views about the merits and need for the current ERCB-operated prorationing plan which allocates the total demand for Alberta light oil among all producing wells in the province. Following deregulation, the demand for Alberta light oil experienced a significant decline, which some industry executives attributed to the constraints of the prorationing plan. A contributing factor — not widely recognized — was the reduced capacity of the pipeline system to deliver oil from Western Canada to available markets. Increasing production of bitumen from in-situ oil sands projects resulted in lower pipeline transportation capacity because of the greater difficulty of pumping the heavier oil. The pipeline system required expansion and that work is now underway.

In the meantime, the controversy about the efficiency of the prorationing plan led to its modification through the introduction of a supplementary sales system for Alberta light oil. Under this plan, buyers can advertise to purchase Alberta's shut-in oil at negotiated prices. This system provides Alberta operators who have shut-in oil the opportunity to make supplementary sales at "spot" prices. Introduced in October 1985 on a trial basis, the supplementary sales plan has reduced the amount of shut-in Alberta oil. During the last three months of 1985, the supplementary plan accounted for additional crude oil sales of 6,000 cubic metres (38,000 barrels) per day.

The deregulation of natural gas prices will not be fully felt until the end of the transition period in November 1986. However, deregulation in the United States already is having a major impact on the Alberta industry. Extreme competition among rival suppliers in the U.S. has led to price cuts and Canadian suppliers, in turn, have reduced prices in order to hold their share of U.S. markets. The relaxation of U.S. government controls has also led to the emergence of a new "spot" market for short-term sales of natural gas, as opposed to the traditional long-term, set-price contracts.

As we go to press, the world crude oil market is in turmoil and world prices have fallen from US$28 per barrel in mid-December, 1985, to less than US$20 by the end of January, 1986. What will happen to prices in the next year or two is quite uncertain and what impacts these events will have on development in Alberta is not clear.

Alberta's Energy Resources

...what they are and who uses them

Alberta is fortunate in both the variety and magnitude of its energy resources. Coal and natural gas were being produced in the province even before its inception in 1905, but the major wave of oil and gas development didn't occur until the discovery of oil at Leduc in 1947. Since then, there have been both substantial discoveries and production of oil and gas.

Reserves and Production

Taken together, conventional oil and natural gas reserves account for about 15% of the province's energy reserves (oil 4%; gas 11%). However, 1985 production of these two resources represented 85% of the total energy produced in Alberta (oil 37%; gas 48%). The remaining 15% of energy production came from oil sands and coal in about equal proportions.

This difference — particularly between oil reserves and oil production — marks an important trend for the future; conventional oil production will decline further in relative importance, while bitumen (from oil sands) and coal, and to a lesser extent gas, will be the energy resources of the foreseeable future.

Distribution

Approximately 28% of the energy produced in Alberta in 1985 was used within the province; consumed as home heating fuel, delivered to Alberta refineries for upgrading and resale, and used to generate electricity; 43% was delivered to other provinces and 29% was exported to other countries.

There were notable differences in the sales pattern for each energy resource. Only 18% of our conventional crude oil was used in Alberta, in 1985, while 21% was exported to the United States. In contrast, 29% of the natural gas produced in 1985 was used by Albertans — mostly to heat our homes — while 36% was exported to the U.S. More than two-thirds of our coal production was used in Alberta (mostly to generate electricity) with almost all the remainder being exported to the Far East, Europe and South America.

1. Alberta's Energy Resources (in petajoules*)

Remaining Reserves at the end of 1985		
	Conventional Oil and Equivalent	25,400
	Natural Gas and Equivalent	73,000
	Bitumen and Synthetic Crude Oil	154,100
	Coal	419,500

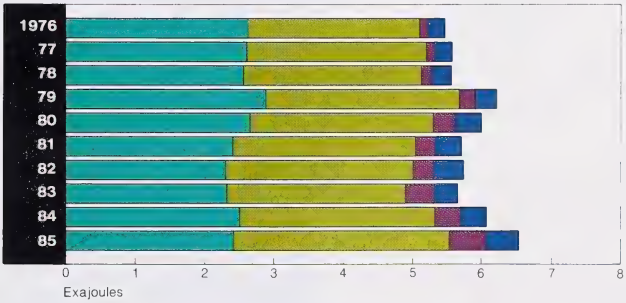
1985 Production		
	Conventional Oil and Equivalent	2,430
	Natural Gas and Equivalent	2,940
	Bitumen and Synthetic Crude Oil	530
	Coal	470
	Hydro	10
	Total	6,380

1985 Sales		To Alberta	To Other Provinces	Exports	Total
	Oil	430	1,500	500	2,430
	Gas	730	1,080	1,130	2,940
	Bitumen and Synthetic	240	150	140	530
	Coal	340	30	100	470
	Hydro	10			10
	Total	1,750	2,760	1,870	6,380
	Percent of production	28	43	29	100

* One petajoule is equal to 1 billion cubic feet of gas, 164,000 barrels of oil, or 60,000 tonnes of coal.

2. Alberta Energy Resources

10-year production



Exploration, Development and Production

...the challenge of finding and producing energy

Exploration for Alberta's energy resources differs substantially depending on the resource. For conventional oil and gas, successful exploration is a precondition to future activity. Finding these reserves is difficult and frequently involves considerable financial risk.

The resource maps on page five show the areas in which conventional oil, coal, oil sands and gas deposits have already been discovered. Much of the remaining area has been tested by exploratory drilling, but this has so far been unsuccessful in finding additional reserves in commercial quantities. To date, more than 5,000 oil pools have been discovered in the province. However, about half Alberta's conventional oil production comes from just 25 major pools.

In contrast, more than 18,000 gas reservoirs have been identified in Alberta, although most are relatively small, requiring only one or two wells to recover the reserves.

Exploration for conventional oil and gas reserves is based on geological and seismic activities that provide clues to the subsurface structures. Potentially favourable locations are thus identified and then tested by exploratory drilling.

Exploration for reserves of oil sands and coal is not as active because substantial resources already have been confirmed. Development of these resources depends largely on market demand (and thus price) versus the cost of production.

Oil, Gas and Bitumen

In 1985, the ERCB issued an all-time-record 8,763 well drilling licences. The previous high was 7,820 licences in 1980. The 1985 total was 22% more than 1984, and 77% more than 1983; a positive trend for the Alberta economy. A renewed emphasis on exploration for conventional oil reserves, that began in late 1982, has continued strongly throughout 1985.

The continued constraints on marketing Alberta gas in the United States, coupled with large volumes of produceable gas that are shut-in, has had the expected dampening effect on gas exploration activities. Successful gas wells drilled in 1985 totalled 1,800, down from almost 4,000 in 1980.

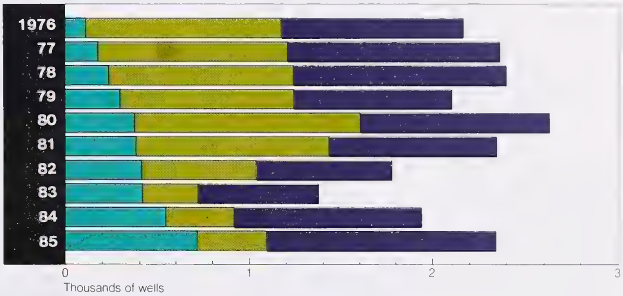
The rapid development of in-situ oil sands operations in Alberta continued in 1985. Fifteen new projects were approved by the ERCB and a total of 1,095 oil sands wells were drilled. Alberta's production of bitumen increased from 4,800 cubic metres (30,000 barrels) per day in December 1984, to an estimated 12,000 cubic metres (75,000 barrels) per day by December 1985. Part of this substantial increase is attributable to Esso's huge Cold Lake project which began producing bitumen during the year.

Production of synthetic crude oil (upgraded bitumen), from the two oil sands mining plants in the Fort McMurray area, amounted to 9.5 million cubic metres (60 million barrels), up from 7.7 million cubic metres (48 million barrels) in 1984.

3. Oil and Gas Wells — Exploration

The last ten years has seen steady increase in exploratory drilling for oil. The current rate is almost twice that of the early 1980s.

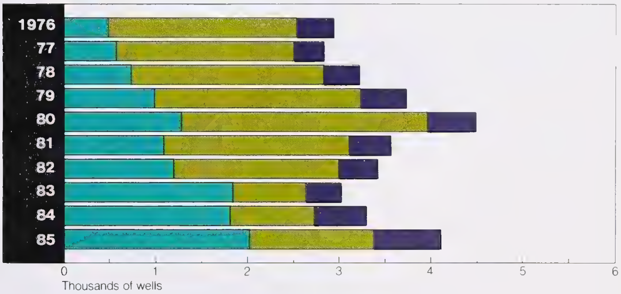
■ Abandoned and Other



4. Oil and Gas Wells — Development

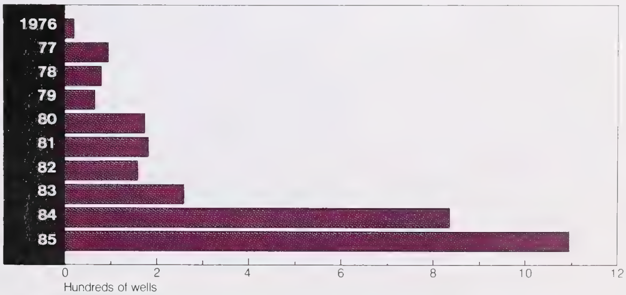
Successful oil wells accounted for almost one-half of total development wells in 1985, as compared to only one-sixth in 1976. In contrast, the relative importance of gas completions declined, from 70% to 30% of total completions.

■ Abandoned and Other



5. Oil Sands Wells

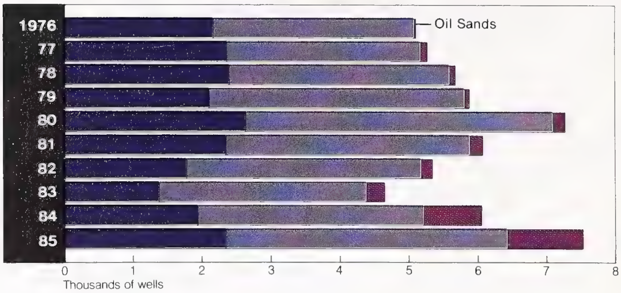
ERCB approval of projects to produce bitumen from oil sands reserves in the Cold Lake and Elk Point areas accounts for the rapid increase in oil sands wells drilled during the last few years.



6. Total Wells Drilled

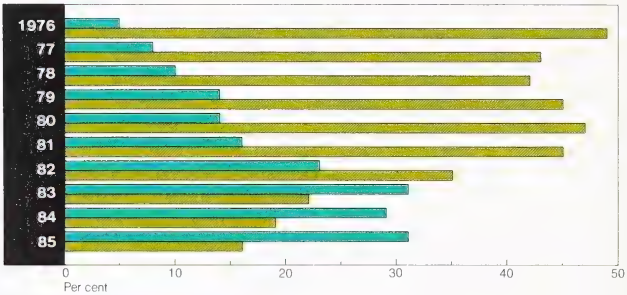
While exploratory efforts declined during the middle years of the 10-year span charted here, by 1985 it had returned to its previous importance. Oil sands drilling has provided a significant additional boost during the last two years.

■ Exploratory
■ Development
■ Oil Sands



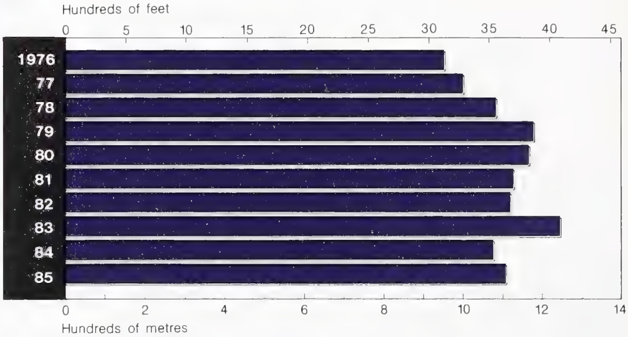
7. Drilling Success

Three trends in success ratios for exploratory drilling: Total success has declined since 1981, from more than 60% to less than 50%. The gas share has declined steadily since 1980. The share of oil drilling success has increased consistently throughout the decade.



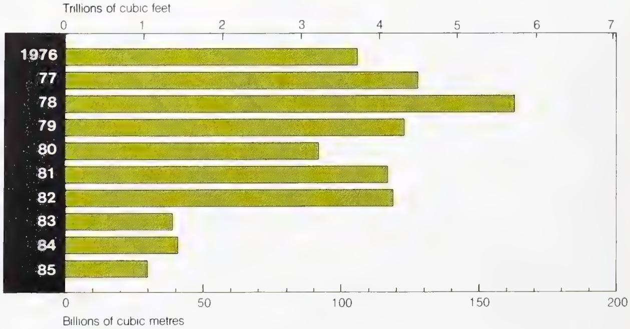
8. Average Depth of Wells

The average depth of oil sands wells is about half that of conventional wells. Even though the number of oil sands completions increased significantly in 1985, average well depths increased only modestly.



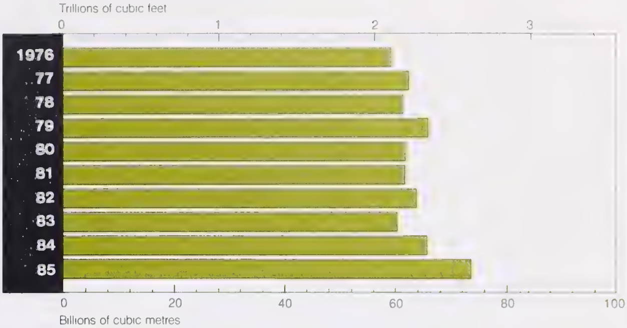
9. Additions to Established Gas Reserves

Additions to reserves over the last three years are about one-third of earlier years because the large volume of shut-in gas in Alberta and difficult market constraints have led to reduced exploration, as shown in charts 3 and 7. Established reserves include gas delivered to the pipeline system at field plants after removal of propane, butanes, pentanes plus and sulphur.



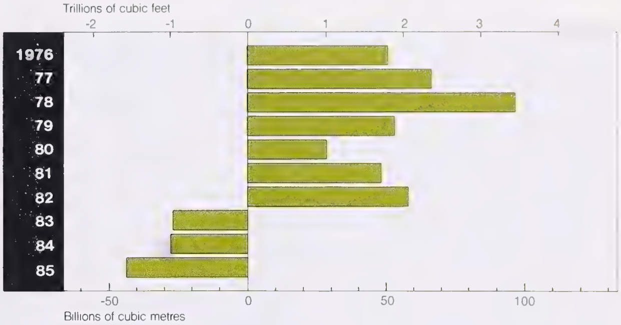
10. Gas Production

Production of marketable gas in 1985 was 10% greater than in 1984, but still substantially below what could have been produced had there not been market constraints. Additional information on the relationship between production and productive capacity is shown in chart 49.



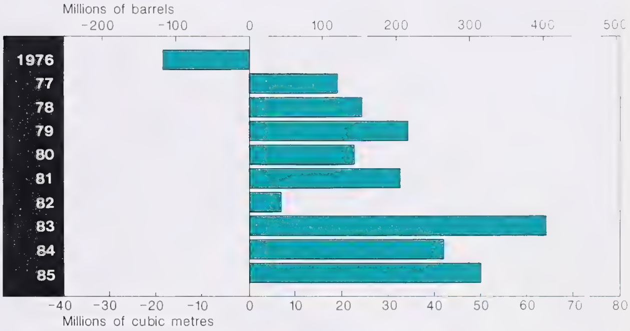
11. Changes in Remaining Established Gas Reserves

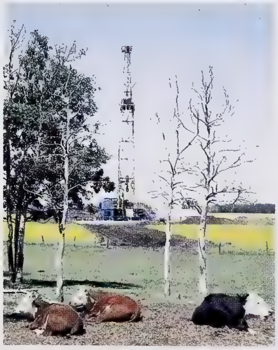
For the last three years, additions to gas reserves have been less than production and Alberta's remaining gas reserves (inventory) have declined. (See chart 56 for remaining reserves.)



12. Additions to Established Oil Reserves

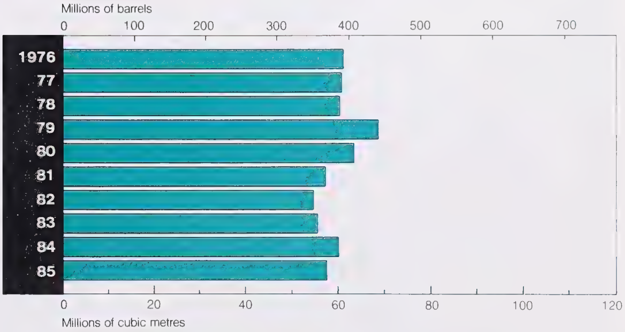
Additions to conventional oil reserves during each of the last three years have been greater than during any of the previous seven years.





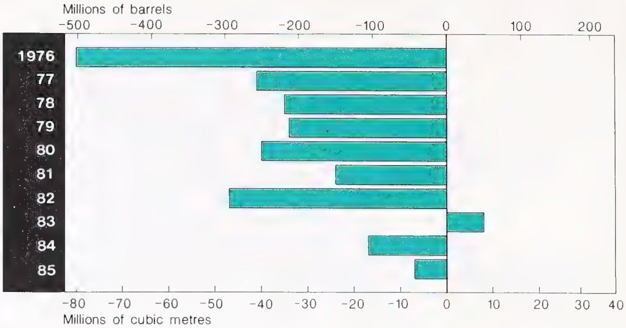
13. Oil Production

Oil production in 1985 was 5% less than in 1984 because of shut-in production caused by adjusting to deregulation of oil prices and to limitation in pipeline delivery capacity.



14. Changes in Remaining Established Oil Reserves

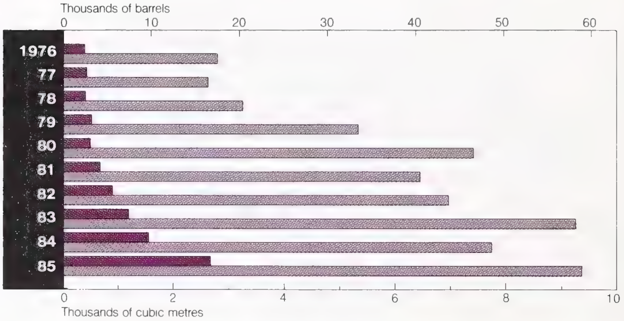
As has occurred in each year since 1969, except for 1983, additions to oil reserves in 1985 were less than production. However, the shortfall was relatively small.



15. Bitumen and Synthetic Crude Oil Production

Bitumen recovered at the two oil sands mining projects is upgraded into synthetic crude oil, whereas bitumen recovered from wells at in-situ projects is diluted with pentanes plus and pipelined to refineries for processing.

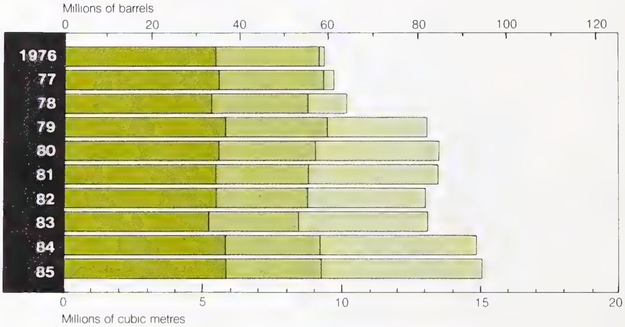
■ Bitumen
▨ Synthetic Crude Oil



16. Natural Gas Liquids Production

Production of propane, butanes and ethane remained about the same in 1985 as in previous years. Note: In this chart, pentanes plus are excluded but are later included with conventional oil in charts 24 and 25.

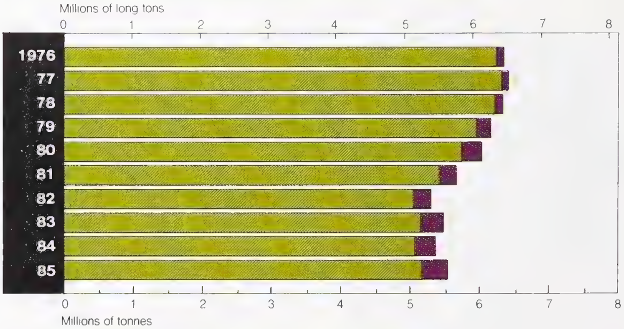
■ Propane
▨ Butanes
□ Ethane



17. Sulphur Production

Sulphur recovered at sour gas plants and oil sands plants was modestly higher in 1985 than in the previous year. This was due to increases in both gas production and synthetic crude oil production.

■ Gas Plants
■ Oil Sands Plants



Coal

Exploratory drilling for coal increased in 1985, after three years of continuous decline. This increase occurred in the Plains and Mountain regions with only slight change recorded for the Foothills region.

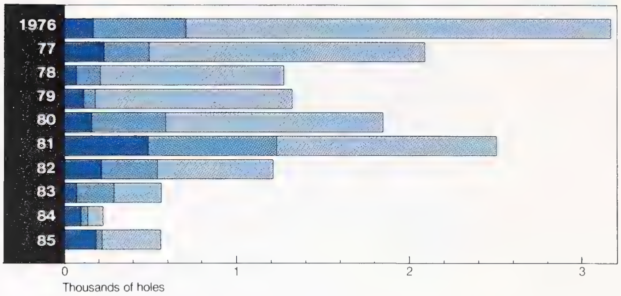
There was little expansion of existing Alberta coal mining operations, except at Manalta's Montgomery mine, near Hanna. This mine is being expanded to deliver 1.5 million tonnes of subbituminous coal per year to the first unit of the new Sheerness electric generating station.

Canada's largest coal mine, TransAlta's Highvale mine, in the Wabamun area west of Edmonton, delivered 11 million tonnes of subbituminous coal to the Sundance and Keephills electric generating stations in 1985.

18. Exploratory Coal Holes

Coal exploration has remained low during the last three years because of oversupply in world markets and because large reserves have already been identified.

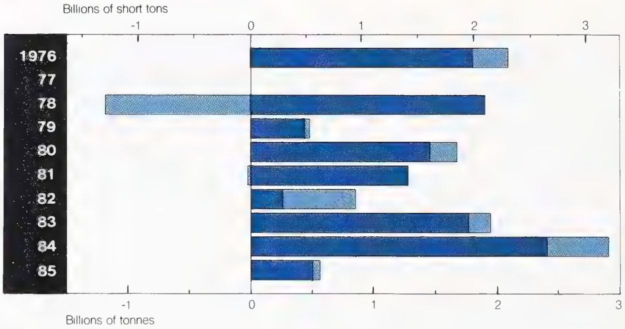
■ Mountains
▨ Foothills
░ Plains



19. Additions to Coal Reserves

Notwithstanding the limited exploratory drilling, substantial additions to coal reserves have been made during the last three years and generally over the last ten years. In 1985, ERCB estimates of coal reserves increased by about 600 million tonnes.

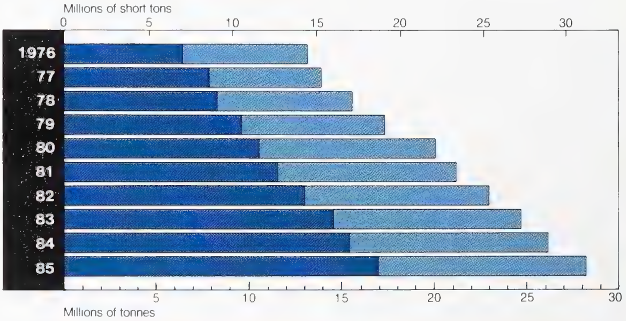
■ Subbituminous
▨ Bituminous



20. Coal Production

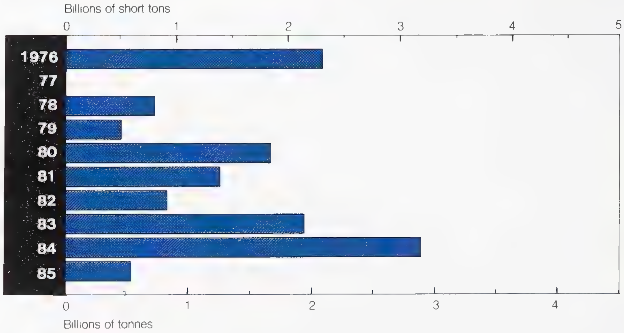
Production of subbituminous coal to supply electric generating plants increased by 8% in 1985. Production of metallurgical coal, which is mainly exported, declined. Note: Production figures are in millions, whereas additions to reserves are given in billions.

■ Subbituminous
▨ Bituminous



21. Changes to Coal Reserves

In 1985, additions to coal reserves exceeded production by over 500 million tonnes.



Hydro and Electric Energy

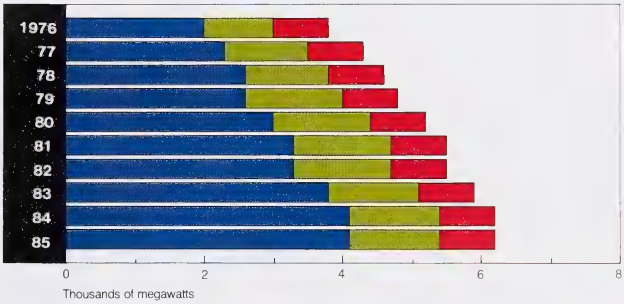
Due to slower growth in Alberta's demand for electricity than had been forecast, the ERCB approved a delay in the start-up of the two new electric generating units at the Genesee station, near Edmonton, and the second unit at Sheerness, near Hanna. The first Sheerness unit will be commissioned in early 1986. After several years of preliminary studies, the proposed Slave River hydro project in northern Alberta was put on indefinite hold.

A 500-kV electric transmission line linking Alberta and British Columbia through the Crowsnest Pass was energized in late 1985. This tie-line between the mainly thermal-based electric system in Alberta and the hydro-based system in British Columbia will provide increased reliability for both systems and allow the exchange of electric energy should that need arise.

Applications to extend the province's 240 kV transmission system in northeastern Alberta were received by the ERCB in 1985 from Alberta Power Limited and TransAlta Utilities Ltd. These proposals would see two circuits constructed from Fort Saskatchewan to the Whitefish Lake and Cold Lake areas and a single circuit from Whitefish lake to Fort McMurray. The extended transmission lines will serve oil sands developments and will also increase the reliability of power supply to Fort McMurray. The first phase of the extension, from Fort Saskatchewan to Fort McMurray, was approved by the ERCB in late 1985.

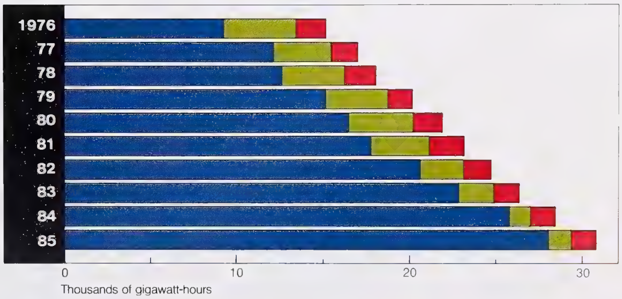
22. Electric Generating Capacity

Construction of both the Genesee power plant and the second generating unit at Sheerness were put on hold in 1985. The first generating unit at Sheerness became operable in January 1986.



23. Electricity Generated

Electric energy generated in 1985 was 8% greater than in 1984. Coal generated more than 90% of the total.



Sales and Distribution

...getting energy resources to markets

With less than one-third of Alberta's energy resources being processed in the province, development of energy resources has always depended on finding suitable markets outside the province. Alberta's land-locked position and distance from major markets requires an efficient transportation network in order to remain competitive.

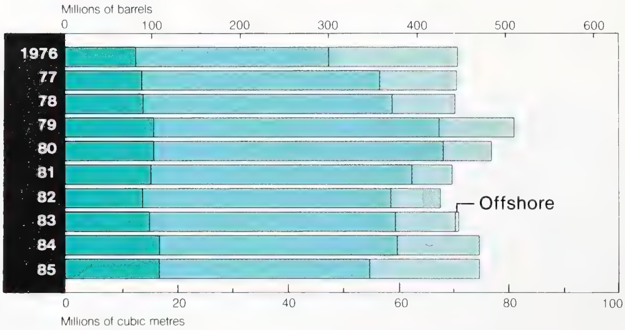
During the past 35 years, an extensive pipeline network has been constructed which enables Alberta producers to supply oil and gas to virtually all the major Canadian markets and to many areas in the United States. For example, the first phase of the oil delivery network was completed in 1950, when a pipeline was built from Edmonton to Lake Superior. That line was subsequently extended to Sarnia, Toronto, Buffalo, Chicago and eventually Montreal. Other pipelines were added to supply the Vancouver and Puget Sound areas and the states south of the Alberta border.

Most of Alberta's markets for coal and sulphur are more distant and delivery of these resources depends on a combination of rail and shipping. This increases transportation costs and thus affects the producers' ability to compete with producers in other countries. This situation is particularly true for coal. The world demand for sulphur has increased significantly in recent years and rising prices have overshadowed transport costs.

24. Markets for Oil and Equivalent

Deliveries to Alberta markets remained the same in 1985, but were lower to other parts of Canada. Deliveries to U.S. refineries increased by 14,000 cubic metres (90,000 barrels) per day.

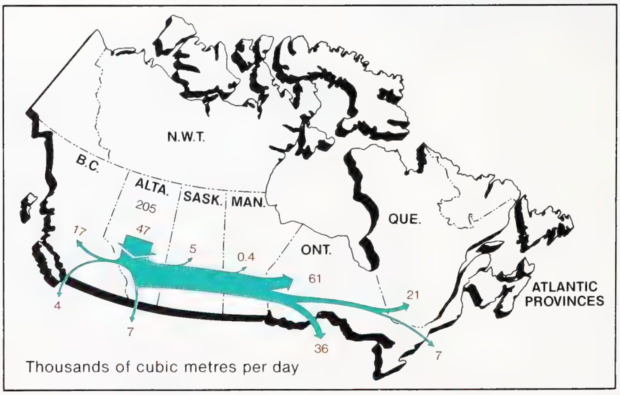
■ Alberta
■ Other Canada
■ U.S.A.



25. Markets for Oil and Equivalent in 1985

Alberta's average daily deliveries of oil and equivalent, in 1985, totalled 1.3 million barrels; 300,000 to Alberta refineries; 660,000 to other Canadian provinces; and 340,000 to U.S. markets. Alberta refineries supply 60% of the petroleum products presently being used in the four western provinces.

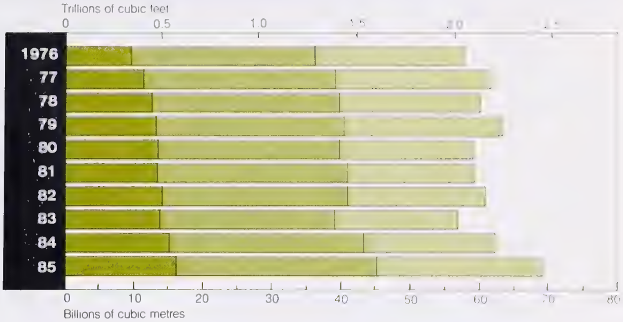
Legend
Production
Deliveries



26. Markets for Gas

Deliveries of gas increased in all Alberta's market areas, especially in the U.S. Total deliveries of gas increased by 11%, but the increase to U.S. markets was about 25%.

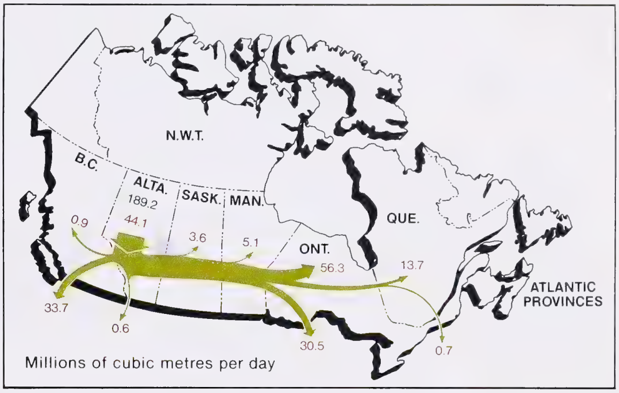
- ▨ Alberta
- ▨ Other Canada
- ▨ U.S.A.



27. Markets for Gas in 1985

Total gas deliveries in 1985 were 6.6 billion cubic feet per day; 1.5 billion to Alberta consumers; 2.8 billion to other Canadian consumers; and 2.3 billion to U.S. markets.

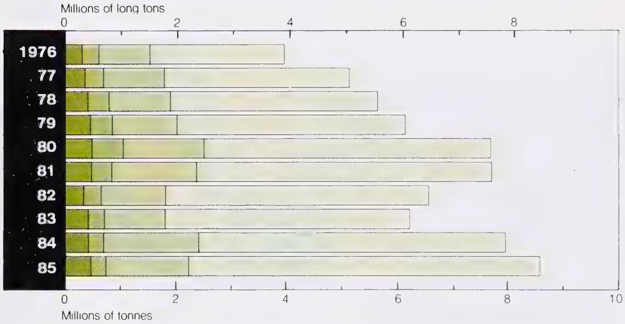
Legend
Production
Deliveries



28. Markets for Sulphur

Deliveries in 1985 were 8% greater than in 1984. Of the 8.6 million tonnes sold, about 3 million tonnes came from stockpiles built up in previous years.

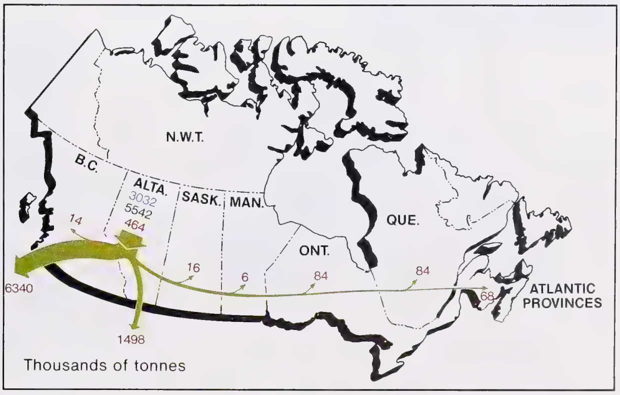
- ▨ Alberta
- ▨ Other Canada
- ▨ U.S.A.
- ☐ Offshore



29. Markets for Sulphur in 1985

Of total sales, 700,000 tonnes were delivered to Canadian markets; about 1.5 million tonnes were sold in the U.S.; and 6.3 million tonnes were sold overseas.

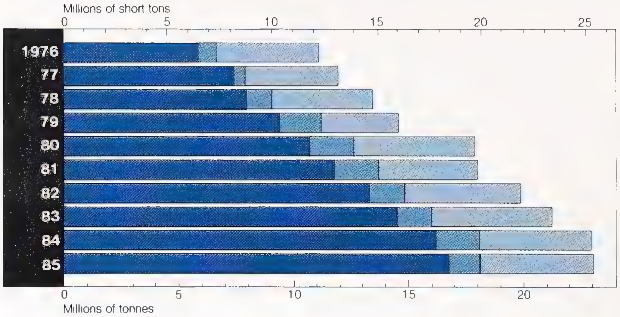
Legend
Production
From Inventory
Deliveries



30. Markets for Coal

Total deliveries of coal in 1985 were about the same as in 1984, amounting to 23 million tonnes.

- ■ Alberta
- ▨ Other Canada
- ☐ Offshore and U.S.A.



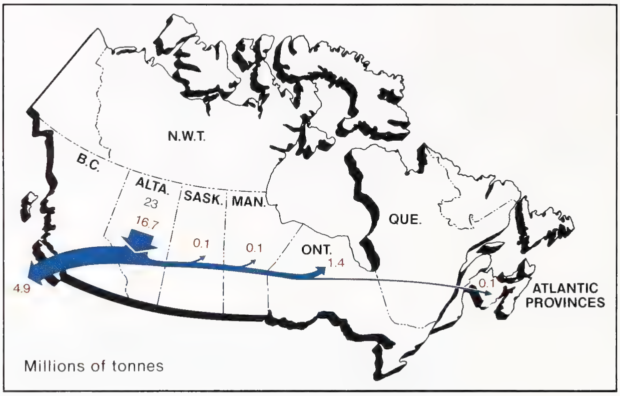
31. Markets for Coal in 1985

A total of 16.7 million tonnes, or 73% of total production, remained in Alberta for electricity generation. Of the remainder, about 1.3 million tonnes was shipped to Ontario, over 4 million tonnes to Japan, and the balance to 12 other countries.

Legend

Production

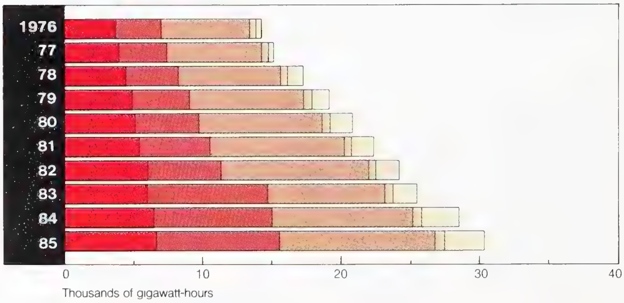
Deliveries



32. Electric Energy Markets

There was a 6.3% increase in Alberta's total electric energy consumption, with increased industrial demand accounting for about one-half the increase.

- ■ Residential and Farms
- ▨ Commercial
- ▨ Industrial
- ☐ Transportation
- ☐ Industrial On-Site Generation



Revenues, Investment and Employment

...energy powering Alberta's economy

The sale of Alberta's energy resources generated total revenues in 1985 of $25.4 billion — a new record, surpassing the total in 1984 by $400 million. Oil production (including conventional oil, pentanes plus, synthetic crude oil and bitumen) generated $14.9 billion, which is nearly four times its contribution ten years ago. The sale of natural gas (including butanes, propane and ethane) has increased from $2.5 billion in 1976 to an estimated $8.9 billion in 1985. Sulphur sales have increased from $69 million in 1976 to an estimated $957 million in 1985 and coal sales have increased from $235 million in 1976 to an estimated $550 million in 1985.

These dramatic increases have been primarily due to increasing energy prices during much of the decade. The average price for a barrel of oil produced in 1976 was $10.16, compared to an estimated average price in 1985 of $37.78.

Investment by the energy industry in developing Alberta's energy resources has increased substantially — up from $2 billion in 1976, to about $5 billion in 1984 and an estimated record in 1985 of $7.3 billion.

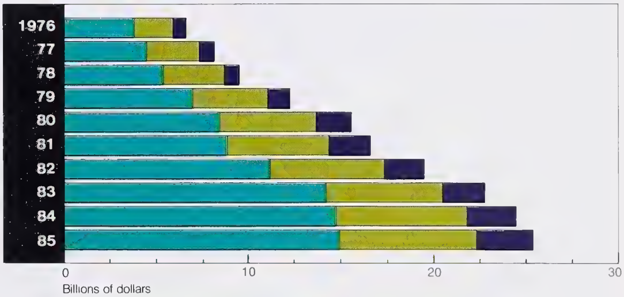
Direct employment in the Alberta energy industry has more than doubled since 1976 and 18,000 new jobs were created in Alberta in 1985. A total of 95,000 people were directly employed in the energy industry in 1985; 81% in oil and gas drilling and development; 7% in oil sands; 4% in electricity generation; 2% in coal and 5% in the petrochemicals industry.

In addition, each direct job in the energy industry generates an estimated 2.7 additional jobs in other sectors of the economy, notably in manufacturing and service industries.

33. Gross Revenues — All Hydrocarbons

Gross revenues from energy production increased by about 4% to an all-time-record in 1985 of $25.4 billion. Sales of oil and equivalent contributed 59% and gas (including butanes, propane and ethane) accounted for an additional 35%.

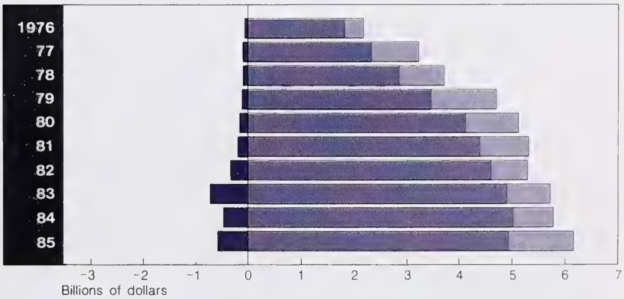
■ Other



34. Alberta Government Energy Revenues

Government revenues from the energy industry increased by 5% in 1985 and amounted to $5.6 billion after subtracting $570 million of incentive payments.

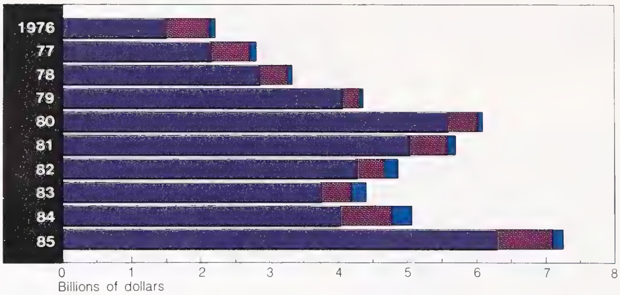
■ Payments
■ Revenues — Royalties
▨ Revenues — Other



35. Energy Investment in Alberta

During 1985, the energy industry invested a record $7.3 billion in searching for and developing Alberta's energy resources — a 43% increase from 1984. The highest previous investment was $6.1 billion in 1981.

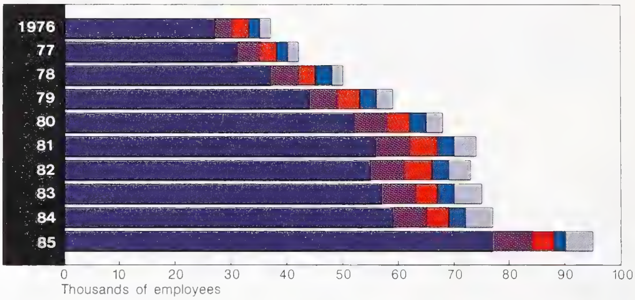
- ▨ Gas and Conventional Oil
- ▨ Oil Sands
- ▨ Coal



36. Employment in Alberta's Energy Industry

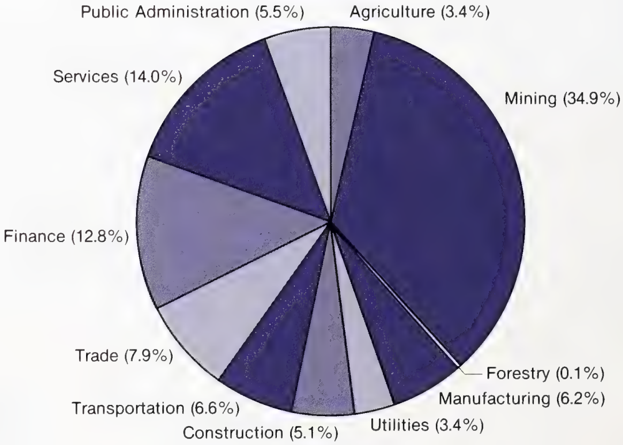
Employment in Alberta's energy industry increased by 23% with the addition of 18,000 new jobs in 1985.

- ▨ Oil and Gas
- ▨ Oil Sands
- 🟥 Electricity
- 🟦 Coal
- ☐ Petrochemicals



37. Alberta Gross Domestic Product (1984)

Petroleum industry contribution to Alberta's GDP is included under Mining and represents almost 35% of total Alberta GDP in 1984.



Environmental Issues

...concerns arising from resource development

Development of Alberta's energy resources has resulted in a maze of energy facilities dotting the provincial landscape. The construction and operation of these facilities inevitably causes some environmental impacts and disturbances to lifestyle. These are, of course, some of the trade-offs for the related economic development, revenues and employment. To be acceptable to Albertans, however, these impacts must be kept to a minimum. By establishing strict environmental performance standards, and then monitoring actual performance and effectively enforcing regulations, the ERCB and government departments are able to minimize or prevent undue environmental and lifestyle impacts.

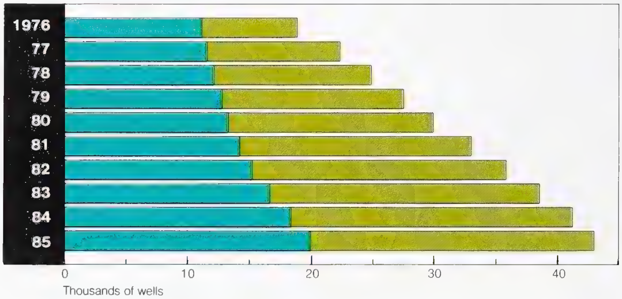
From time-to-time, however, mechanical equipment will malfunction and human beings will make mistakes. The need, then, is for swift, effective clean-up and careful planning to prevent or reduce the chances of similar incidents in the future. In this section, we comment on environmental developments and related ERCB actions during 1985. The accompanying charts provide statistics on the incidents and accidents that have required attention during the year.

Potential Trouble Sources

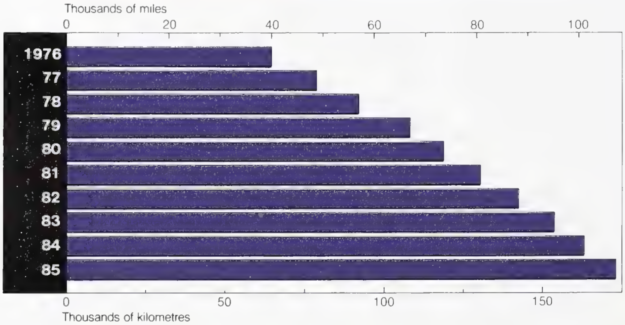
Drilling, construction and operation of energy facilities can, of course, lead to environmental problems. In 1985, the inventory of provincial energy facilities included:

- 7,526 drilling oil, gas and oil sands wells
- 43,000 producing oil and gas wells
- 10,768 oil and gas batteries
- 170,000 kilometres (106,000 miles) of pipelines transporting oil, gas, salt water and other materials
- 447 operating gas processing plants (including 129 sour gas plants)
- 6 coal-fired power plants
- 19 surface and underground coal mines
- 6 oil refineries
- 25 petrochemical plants

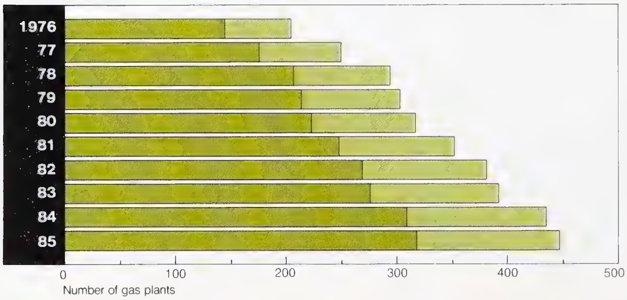
The number of energy facilities already built is substantial and it increases each year. It is against this huge inventory of potential trouble sources that the performance of Alberta's energy industry should be judged.



38. Producing Oil and Gas Wells



39. Pipeline Installed



40. Gas Processing Plants

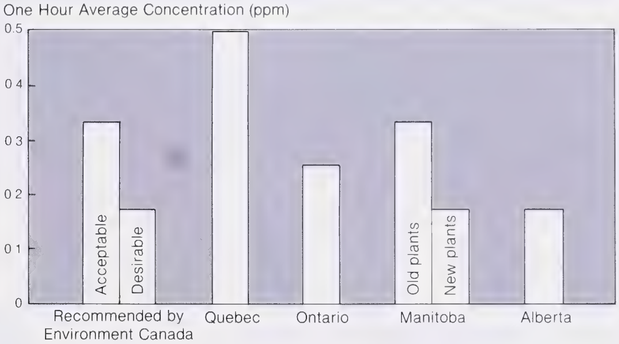
🟩 Sweet
🟩 Sour

Environmental Standards

Alberta's energy facilities must be operated in a manner that will not violate a broad range of environmental requirements, including specific requirements for well drilling operations, returning land affected by major surface disturbances to at least its original condition, standards for clean air and clean water and special requirements imposed on specific projects.

Evidence that the Alberta standards are tough is found in the air quality requirements covering emissions from sour gas operations. Environment Canada recommended, in 1971, "acceptable" and "desirable" air quality standards for sulphur dioxide (SO_2). Alberta adopted the most demanding of these, the "desirable" standard of 0.17 parts per million per hour. This is one of the toughest SO_2 standards in the world.

41. SO_2 Air Quality Standards



Environmental Problems in 1985

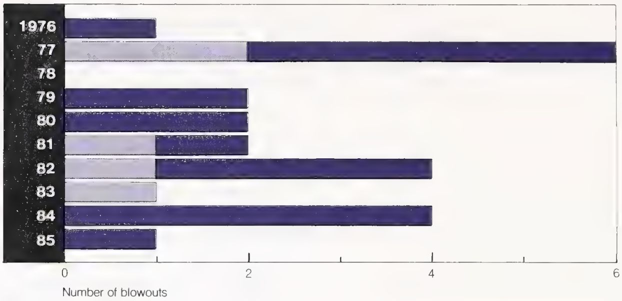
- Well blowouts
  Performance in 1985 was good overall. There was only one incident during the drilling of more than 7,000 new wells and 21 incidents at the more than 43,000 producing wells in Alberta. Five of these incidents involved sour gas, with four workers injured in three of the incidents.

- Pipeline leaks and breaks
  The number of incidents has gradually increased since 1976, but not in proportion to the increasing numbers and length of pipelines. Problems with pipelines carrying salt water, which is very corrosive, continued to dominate. Sour gas pipeline breaks, which are potentially the most serious, represented only 2% of the total.

There has been no pattern to the volume of liquids spilled in the past few years. Quantities were relatively low in 1985.

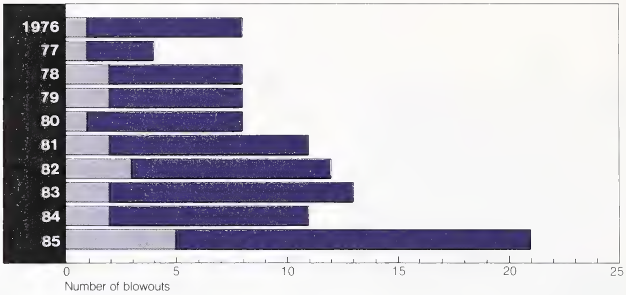
42. Drilling Wells — Blowouts

▨ Sour Gas Wells



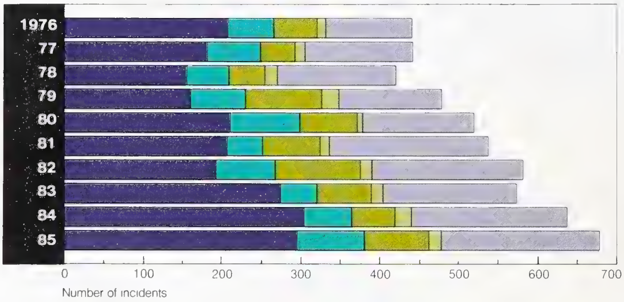
43. Producing Wells — Blowouts

▨ Sour Gas Wells



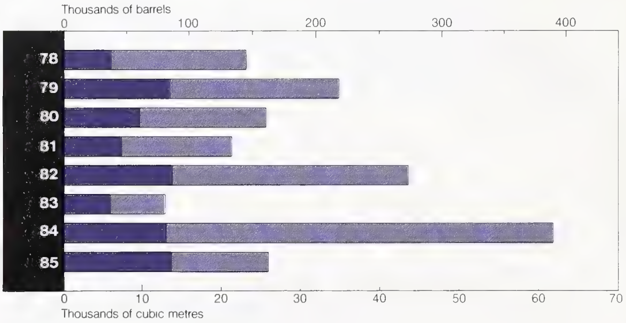
44. Pipeline Leaks and Breaks

■ Water
■ Oil
■ Sweet Gas
▨ Sour Gas
▨ Multiphase



45. Pipeline Liquids Spilled

■ Liquid Hydrocarbons
▨ Salt Water

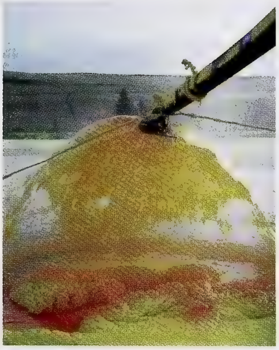


Environmental Initiatives in 1985

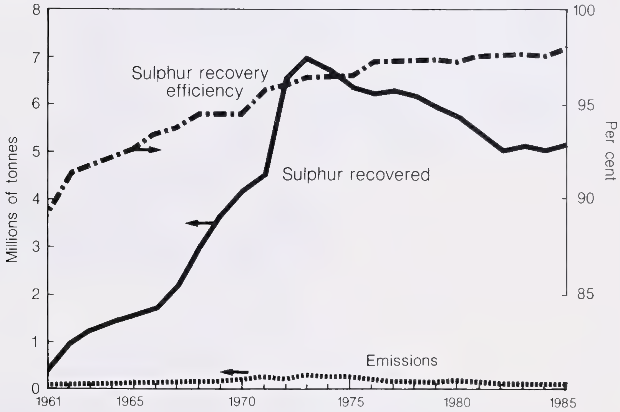
During the year a comprehensive government emergency response plan, designed to manage any release of sour gas, was developed by the ERCB, Alberta Public Safety Services (APSS) and other government departments. This plan involves local and provincial government departments and industry. Two field exercises simulating sour gas well blowouts were successfully carried out during the year. (See Life After Lodgepole, page 41.)

Guidelines for handling and safely disposing of oily sands and wastes were issued by the ERCB in 1985. This sand is produced along with bitumen from in-situ oil sands operations and remains oily even after separation from the bitumen. In the past, oil companies have disposed of this waste product by spreading it on country roads. The new ERCB guidelines establish procedures for receiving regulatory approval, storage facilities, reclamation processing and final disposal.

A comprehensive review of the sulphur recovery requirements at Alberta sour gas processing plants is expected to be completed by late 1986. A task force is investigating recent changes in technology and the economics of gas processing, to determine whether current recovery standards are appropriate. Its report will be reviewed by representatives of the public, the industry, Alberta Environment and the ERCB. A final report will be publicly released in 1987.



46. Sulphur Recovery Rate



Alberta Environment and the ERCB are responsible for ensuring that the standards, regulations and requirements set out in specific project approvals are met. On-site inspections by field staff and responses to public complaints are a major ingredient in this work. During 1985, ERCB inspectors made more than 30,000 checks on all types of energy facilities in Alberta. For example, many of the province's sour gas processing plants were checked at least once during the year. Several inspections were made of each drilling rig working on a "critical" sour gas well.

Air monitors are located near most sour gas plants in the province, particularly the larger plants. A representative analysis in 1983 indicates that for 97.5% of the monitored hours, concentrations were below 0.02 ppm — which is only one-eighth of the air quality standard. For 2.3% of the time, concentrations were between 0.02 - 0.06 ppm; and for 0.2%, they were between 0.06 - 0.17 ppm.

Alberta Energy in Perspective

...current production and future trends

While today Alberta is Canada's energy storehouse and its major supplier of many forms of energy, its position must be considered in comparison to production from other areas of Canada and to expectations for the future.

Alberta in Relation to Canada

Alberta's oil, gas and bitumen reserves currently account for 90% of Canada's total reserves in these three categories. This percentage will decline when the new oil reserves in the Atlantic and Beaufort Sea are evaluated and recognized. Alberta's share of total Canadian coal reserves is approximately 75%.

Alberta's proportion of Canada's total oil and gas production is even higher than her proportion of total reserves and will remain so until the new frontier reserves are producing. Its coal share was 40%. Alberta has relatively little production of electricity from its hydro resources and does not have any nuclear energy. In contrast, several provinces (British Columbia, Manitoba, Ontario and Quebec) depend heavily on hydro for generating electric energy. Nuclear power is an important electric generating source in Ontario.

Alberta's share of total Canadian energy production is currently 67%.

Alberta's combined oil and bitumen production is currently equal to about 15% of United States' total oil production. Alberta gas production is equal to about 15% of U.S. gas production. Oil and gas from Alberta supply 3 and 5%, respectively, of total U.S. demand for these commodities.

47. Alberta vs. Canadian Production (in petajoules)

Remaining reserves at the end of 1985	Alberta	All of Canada	Percentage reserves in Alberta
Conventional Oil and Equivalent	25,400	32,600	78
Natural Gas and Equivalent	73,000	84,900	86
Bitumen and Synthetic Crude Oil	154,100	154,100	100
Coal	419,500	552,000	76
Total	**672,000**	**823,600**	**82**

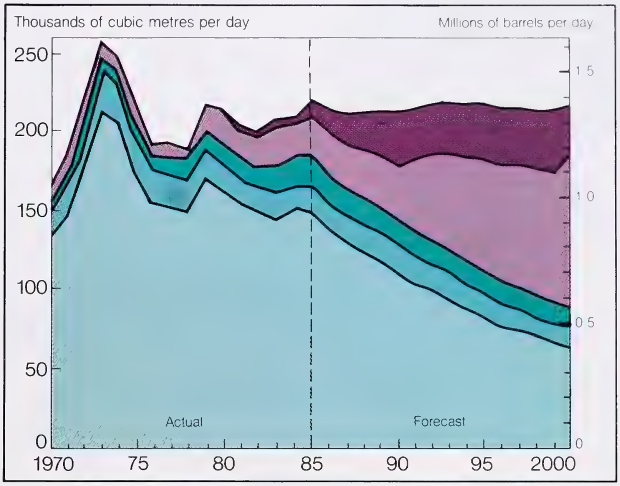
1985 Production	Alberta	All of Canada	Percentage production from Alberta
Conventional Oil and Equivalent	2,430	3,400	71
Natural Gas and Equivalent	2,940	3,100	95
Bitumen and Synthetic Crude Oil	530	530	100
Coal	470	1,250	38
Hydro	10	1,040	1
Nuclear		190	0
Total production	**6,380**	**9,510**	**67**

Current Production in Relation to the Future

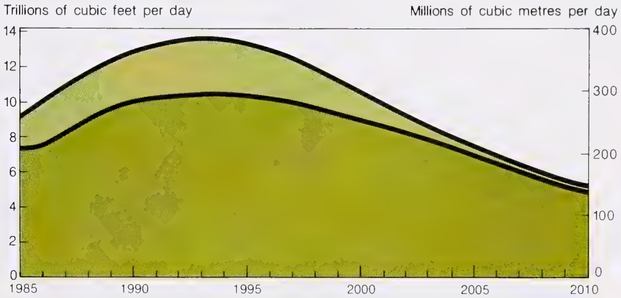
Substantial changes in the production pattern are expected for the future. Alberta's conventional oil reserves and productivity are declining, while production from oil sands is increasing. It is expected that these opposing trends will tend to balance out and that total oil production from Alberta will remain more or less constant.

The situation with respect to natural gas is quite different. Currently, market constraints restrict production to levels substantially below production capacity. However, that situation is expected to change during the next decade with Alberta's natural gas production increasing substantially.

48. Oil Production 1970-2000

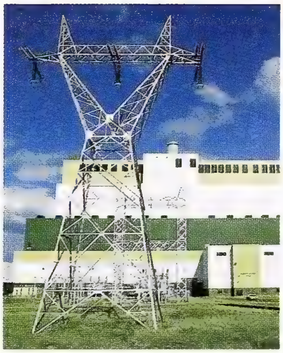


49. Gas Capacity and Production

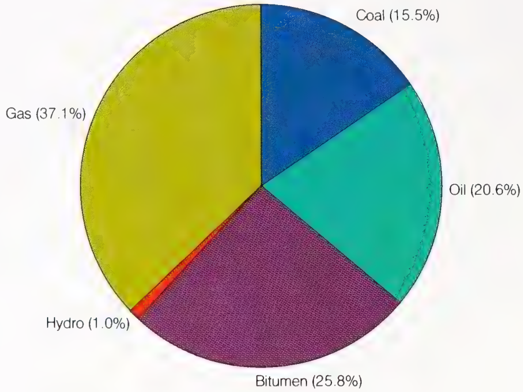


Energy Resource End-Use in Alberta

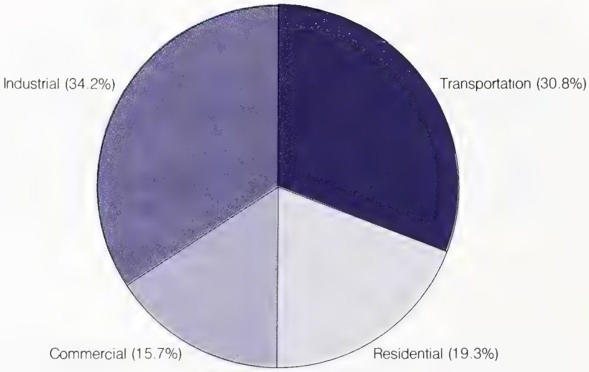
The resources used to meet Alberta's own end-use energy requirements are shown in chart 50. Natural gas is used in Alberta primarily for heating residences, commercial establishments and industry. It also serves as feedstock for Alberta's petrochemical production. Oil and bitumen are used in transportation, and coal and hydro for the generation of electric energy. The relative importance of each end-use category is shown in chart 51.



50. Energy Resources to Meet End-Use Requirements



51. End-Use Requirements in Alberta



Conservation and the ERCB

...what the word means in our name

Making the most of Alberta's non-renewable energy resources is one of the most important objectives in regulating energy developments in the province.

The ERCB is responsible for ensuring that provincial energy resources are developed in a safe, orderly manner that avoids waste, controls pollution and is in the public interest. The ERCB interprets these responsibilities to mean that the recovery of energy resources should be optimized or, as our name attests, "conserved", not wasted. The ERCB has been working since the early years of Alberta's energy industry to maintain a reasonable balance between the extremes of recovering as much of the resources as possible, regardless of cost, or recovering only the "cheapest" reserves, leaving in the ground those reserves that are more costly to recover.

The nature of the geology in which each energy resource is found, and how it is produced, has a major impact on how much of the reserves will be recovered. If production is by surface mine (as used for most coal and some oil sands reserves) then total recovery within the mined area can be very high. Recovery from conventional oil pools may be as low as 5% or as high as 80-90% of the oil in place, depending on the nature of the reservoir and the type of oil.

Conservation

Achieving optimum recovery from energy resources is difficult and requires sophisticated technology and careful controls. This is particularly important in maximizing oil recovery because only a small fraction of the oil can normally be recovered before the natural energy, which causes the oil to flow in the reservoir, is exhausted. Additionally, even this limited natural energy can be wasted if production operations are not carried out carefully. That is why the ERCB limits the rate at which wells can produce and restricts the amount of gas and water (which are natural energy forces in the reservoir) that can be produced with the oil. In many instances, operators are required to reinject gas or water to maintain reservoir pressure.

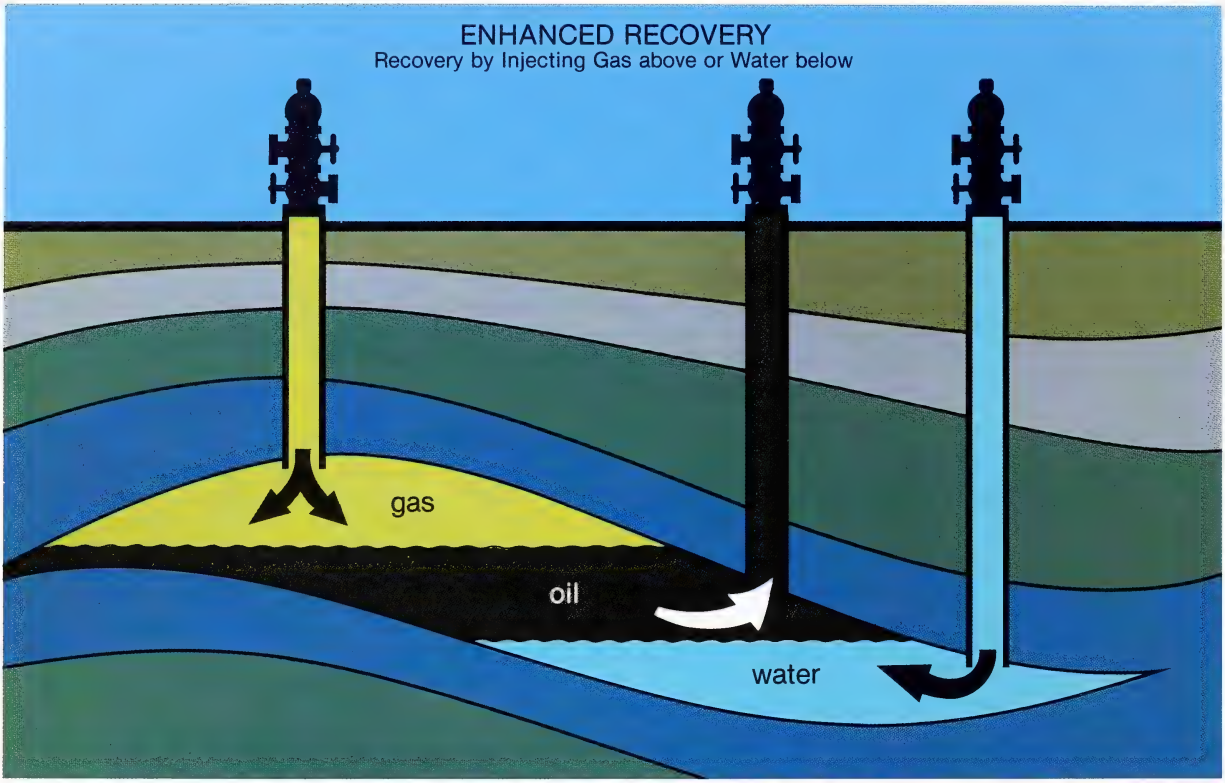
Achieving Optimum Recovery

For conventional oil reserves, achieving optimum recovery requires examining whether improvements could be achieved by supplementing the natural reservoir energy by injecting fluids into the reservoir. This is called enhanced oil recovery (EOR).

At the end of 1985 there were 607 EOR projects operating in the province. They ranged in size from those with single injector/producer wells, to complex projects of 133 injection wells pressure-maintaining 400 producing wells.

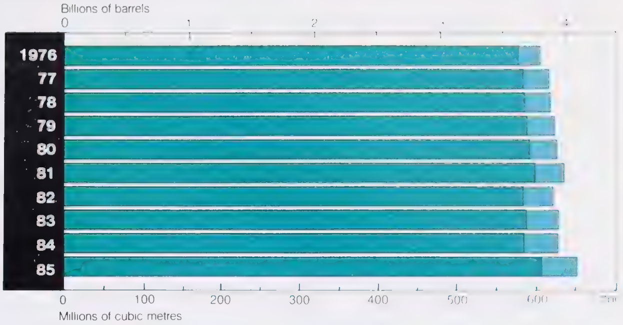
Without EOR operations, only 20% of the conventional oil reserves so far discovered in Alberta would be recoverable. EOR operations have increased the average recovery rate to more than 28%, adding more than 651 million cubic metres (4 billion barrels) to Alberta's total recoverable oil reserves, as shown in chart 52.

Most EOR projects involve injecting water or gas into an oil reservoir. However, an important type of enhanced recovery operation receiving increasing attention is the injection of solvent, such as ethane, propane or carbon dioxide, to flush the oil from the small pore spaces in the rock. As might be expected, this is a costly operation because of the capital investment in equipment and the cost of producing or purchasing the required solvent. The Alberta Government recognizes these additional costs and provides reduced royalty rates for operators implementing this kind of EOR development.



Another important conservation activity is ensuring that the gas unavoidably produced with oil (called solution gas) is not wasted by being flared. The ERCB maintains close watch over these operations to ensure that, wherever it is economically feasible, the gas from oil production is gathered, processed and delivered to the provincial gas gathering system. More than 90% of total solution gas has been conserved for most of the last decade and the remaining 10%, which is too costly to process, has been the cause of most of the flares that can be seen at night dotting the Alberta landscape. The percentage of solution gas being conserved has declined somewhat in recent years and in 1985 was 88%. This is the result of increased oil discoveries which take several years to fully develop and to design and install the necessary conservation facilities. Additionally, many of the discoveries are relatively small which frequently leads to higher conservation costs.

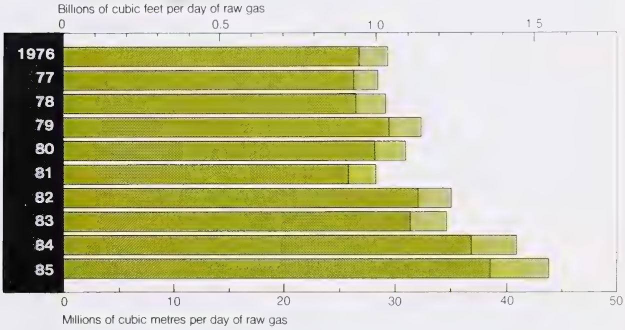
52. Enhanced Oil Recovery



53. Oil Recovery Rates

	Primary Recovery	Enhanced Recovery	Total
Light Oil Pools	21.9%	9.6%	31.5%
Heavy Oil Pools	6.9%	3.8%	10.7%
Average	19.6%	8.7%	28.2%

54. Conservation of Solution Gas

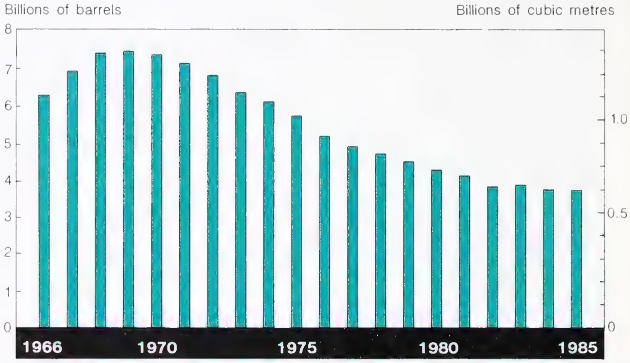


Remaining Resources

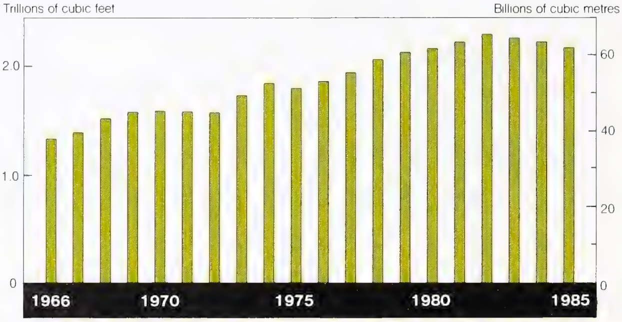
Remaining recoverable reserves of oil have been declining since 1969, except for 1983. In recent years the decline has been arrested due to greater exploration, which was stimulated by attractive royalty, tax and pricing arrangements. In comparison, remaining recoverable established reserves of gas have been increasing since 1975, except for the last three years. As previously indicated, gas exploration has declined markedly in the last few years because of the restricted market demand and large volume of shut-in reserves.

Production rates for each energy resource can be compared to remaining resources in order to calculate how many years the current reserves would last if production continued at the current rate. Chart 57 shows that for 1985, the reserves to production ratio for gas was 23 years and for oil was 11 years. These rates have remained relatively constant over the last decade, although for gas the ratio has declined in recent years and is the lowest since 1972. The decline in the gas ratio is due to the reductions in remaining reserves during the last three years. However, statistics like these do not disclose what would actually happen; rather, they provide an indication of the adequacy of the current reserve base in relation to the current depletion rate. While the conventional oil reserves to production ratio in 1985 was only 11 years, chart 48 shows that production is expected to continue well into the 21st century — but at much lower production rates.

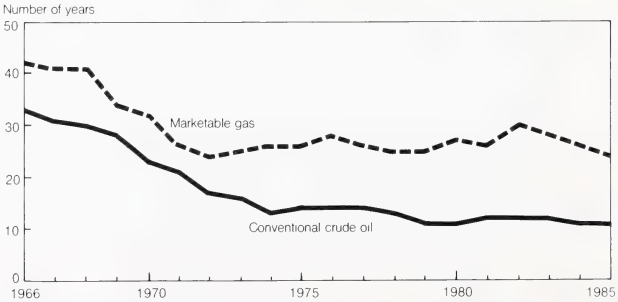
55. Remaining Reserves of Light Oil



56. Remaining Reserves of Gas

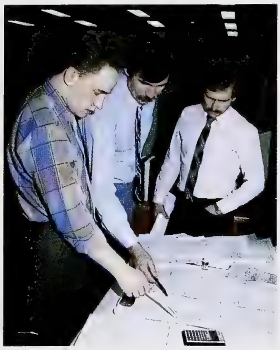


57. Reserves to Production Ratio — Oil and Gas



ERCB Operations

...its work with Albertans and the energy industry



ERCB Responsibilities

The Energy Resources Conservation Board was established by the Alberta Government to ensure the safe and efficient development of energy resources in Alberta. Its responsibilities can be grouped in three major categories:

1) reviewing applications for energy projects,
2) regulating energy facilities,
3) providing advice and information.

The powers of the ERCB are set out in eight Alberta statutes and related regulations. For example, the Energy Resources Conservation Act specifies how the ERCB must conduct its operations and, in particular, specifies the safeguards to be applied when reviewing proposed energy projects. This Act requires the ERCB to give notice to any person(s) who might be "directly and adversely affected" by a proposed energy project. If such a person (technically called an "intervenor") objects to a proposed development, the ERCB must provide him or her with an opportunity to ask questions and to present evidence in support of his or her view.

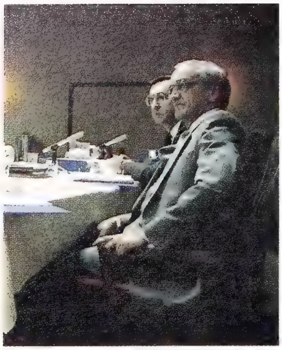
Review of Applications

In 1985, the ERCB received 12,501 applications for energy facilities; 8,763 to drill wells, 2,286 to install pipelines, 39 for new gas plants (of which 12 were to process sour gas), 55 for the removal of gas from the province and 1,358 for a wide variety of other energy-related purposes.

More than 99% of these applications were agreed to by those persons who might have been "directly and adversely affected" and therefore no public hearing was required. Of the 89 applications requiring a public hearing in 1985, 34 were to consider concerns of the public and 55 to resolve disputes of industry.

During 1985, the ERCB continued to emphasize the importance and advantages to applicants of resolving the public's concerns regarding proposed energy facilities before applications must go to formal public hearings. This process — which usually includes discussions between the involved parties — ensures that the public is much better informed and that the applicant fully appreciates specific public concerns. Resolution of outstanding issues is often only possible when all parties are aware of each other's views and the ERCB will continue to actively promote such understanding.

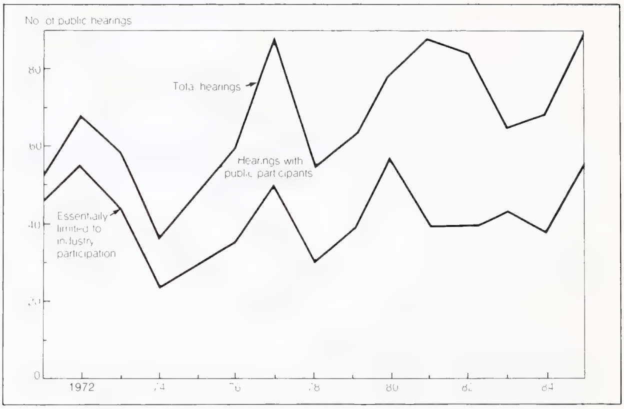
The ERCB has increasingly provided assistance in this learning process and, during 1985, extended its direct involvement in a variety of ways. One example was the processing of an application to drill a critical sour gas well 5 km northeast of the town of Hinton. Before preparing its application to the ERCB, the company had carried out an extensive community involvement program to explain its proposal. Despite this unusually intensive effort, the ERCB received three interventions opposing the proposed well. Thus, a public hearing had to be called and was subsequently scheduled.



The company had already stated that the well would be ignited in the event of any uncontrolled flow of hydrogen sulphide (such as a blowout). The Hinton General Hospital and the Alberta West Central Health Unit intervened because they were concerned that people sensitive to hydrogen sulphide might have to be evacuated should there be even a small leak at the proposed well. Three days before the scheduled public hearing the ERCB convened one final meeting with the company, the intervenors and representatives of the town. During this meeting the company agreed to ignite the well in the event of even a small leak, unless the ERCB permitted a short delay to allow repairs and then only if there was no danger to human health. Specific ignition criteria for that well were then established by mutual agreement of all parties, interventions were withdrawn and no public hearing was necessary.

Reviewing energy applications accounts for 20% of the ERCB's total activities, equivalent to the work of approximately 160 people during the year. The time required to review applications to drill sour gas wells increased significantly in 1985 because of the much more intensive review process resulting from the recommendations of the Lodgepole Inquiry.

58. ERCB Public Hearings



59. ERCB Hearings to Consider Concerns of the Public

Pipelines	9
Well Licences	8
In-situ Oil Sands Development	6
Sour Gas Plants	4
Transmission Lines	3
Other	4
Total	**34**

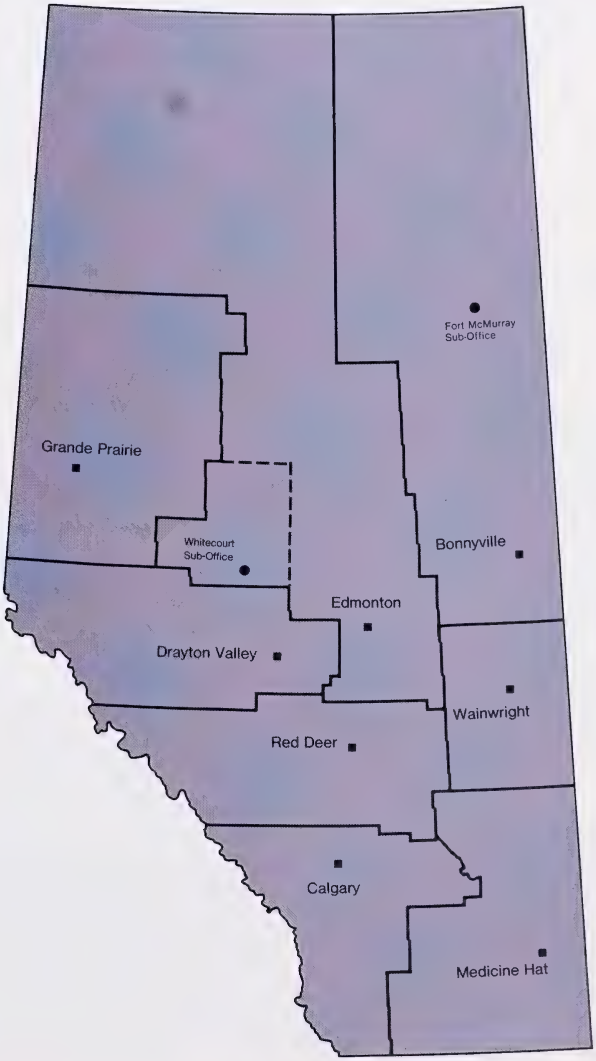
Regulating Operations of Energy Facilities

Proper management of resources is an essential part of the ERCB's legislated mandate to ensure the conservation, or optimum recovery, of Alberta's energy resources. The ERCB oversees essentially all aspects of development and production operations. These activities are carried out by monitoring performance through reports filed by operators and by inspecting the actual energy facilities.

The "desk reviews" cover a wide range of activities, including checking pressure and production performance in the more than 600 enhanced oil recovery projects, reviewing the performance of oil pools where EOR operations have not been initiated, assessing the performance of experimental in-situ projects to recover bitumen, and reviewing production operations where solution gas is not being conserved. (See Conservation and the ERCB, page 31.)

60. ERCB Inspection Districts

■ Area Office Locations



The ERCB requires the services of many technical specialists to carry out this wide range of assessments and its resource management functions account for about 22% of total staff time.

To ensure that energy operations actually are conducted in accordance with standards, regulations and approvals, the ERCB employs 110 inspectors in 9 offices throughout the province. Their basic responsibility is to inspect operations in the field and to investigate any complaints from the public. During 1985, they made 2,442 inspections of drilling rigs, 22,500 inspections of operating oil and gas wells, 625 inspections of gas plants, 860 inspections of pipelines under construction and 6,500 inspections of oil or gas batteries — in all more than 30,000 inspections.

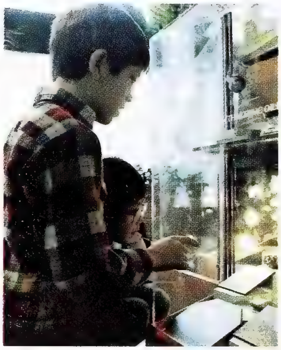
The ERCB's field inspectors have, as support, the full technical and information facilities of the Calgary head office. Where operations are not being performed in accordance with requirements, ERCB inspectors can shut them down, order remedial measures, or initiate prosecution.

The field inspection operations of the ERCB accounted for about 15% of its total activities during 1985.

Providing Information and Advice

The ERCB gathers, records and compiles a wide variety of information relevant to the energy industry. Statistics and reports are compiled from this data and made available, along with non-technical information about energy developments, to the government, interested companies, special-interest groups and individuals. Much of this information assists industry in its search for energy resources, for example:

- well logs
- well drilling samples
- drilling cores
- core analyses
- well and plant production data



During 1985, the ERCB's information activities included:

- many hundreds of publications, for a variety of audiences,
- many thousands of requests for information,
- 12,500 requests for information to the ERCB's Core Research Centre, alone,
- 32,110 visitors to the Energeum (the ERCB's energy museum),
- widespread involvement in rural areas by ERCB field staff,
- In October 1985, the ERCB opened an Energy Information Centre, in Elk Point, to assist people facing intensive energy developments in the Lindbergh Oil Sands Area. This centre — the first of its kind in Alberta — is intended to provide information from the ERCB, government departments, oil companies and special interest groups to help people find answers to energy-related questions,
- During the year, a resident technical officer was appointed to a new sub-office in Fort McMurray. This technical officer carries out inspection and company communication duties at the oil sands mining operations in the area, as well as liaising with local private and public groups,
- The ERCB published a Well Drilling Summary Report for the first time in 1985. This report provides important 1984 statistics about drilling operations, rig inspections, critical sour well inspections and drilling kicks and blowouts.

The ERCB provides a wide variety of advisory services to the Alberta government, to industry and to the public. These include:

- forecasting future Alberta energy requirements, (with a major review launched in 1985, to be made public in 1986),
- forecasting future supplies of energy reserves, particularly oil and gas,
- estimating Alberta's ultimate total energy reserves,
- providing requested technical assistance to the government in such areas as resource evaluation, resource production economics, and on incentive and royalty programs.

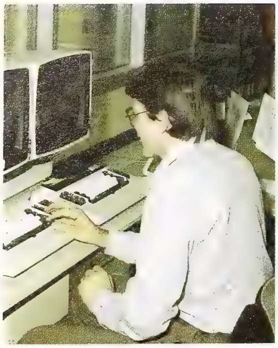
ERCB Expenditures

ERCB's expenditures and numbers of staff have remained relatively constant in recent years, as shown in charts 61 and 62. However, 1985 operational costs were $41.2 million, significantly up from $36.2 million in 1984. This increase was largely due to ERCB's direct work with the public and industry, frequently involving specialist consultants because of the broad and expanding range of subjects. The cost of ERCB operations in 1985, when compared to total energy produced (and assuming that all energy production was converted to barrels of oil), was about 4 cents per barrel, or stated another way, ERCB's net expenditures were about 0.16% of total energy revenues.

Funding of the ERCB's work comes from two sources, in about equal portions; from an administrative levy on operating wells in the province, matched by a direct grant from the Alberta Government.

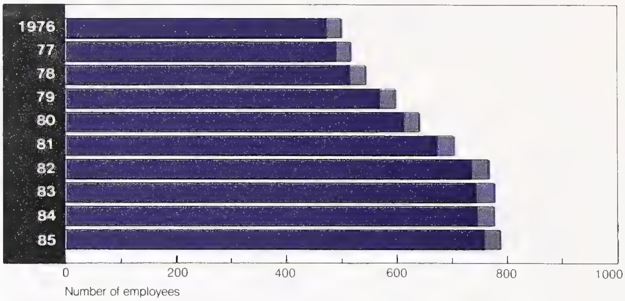
ERCB Organization

The ERCB is headed by six professionally-qualified Board members, appointed by the Alberta Cabinet, each having many years prior experience with the ERCB. In order to carry out its responsibilities, the ERCB employs a staff of 780, including engineers, geologists, economists, statisticians and many other kinds of technical experts. The ERCB staff is divided into 14 departments, located in the ERCB's head office in Calgary and in 10 field offices throughout Alberta.



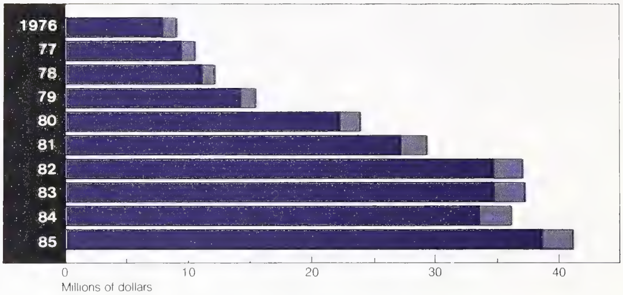
61. Staff

■ Oil and Gas Related
▨ Hydro and Coal Related

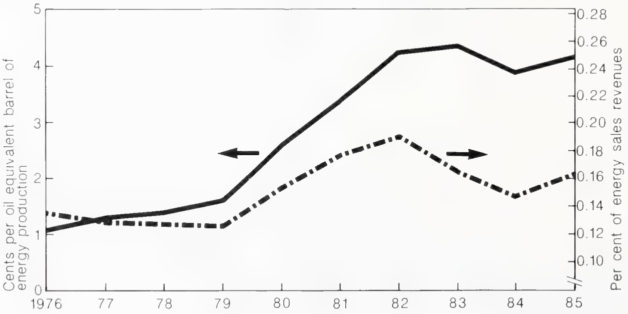


62. ERCB Expenditures

■ Oil and Gas Related
▨ Hydro and Coal Related



63. Index of ERCB Expenditures



64. Summary of ERCB Activities

	Number of staff
Review of Applications and Hearings	160
Resource Management	170
Field Surveillance	120
Information Dissemination	190
Advisory	70
Administration	70
Total	**780**

Life After Lodgepole

...initiatives on sour gas safety

Significant improvements in the practices and procedures for drilling sour gas wells have come into force in Alberta since the Lodgepole blowout in 1982. Many of the 39 recommendations made by the ERCB's Lodgepole Inquiry Panel have already been implemented. Additional recommendations are expected to be implemented in the near future.

Today, all applications to the ERCB to drill oil or gas wells must state whether sour gas is expected. ERCB staff cross-check this information against the ERCB's own geological data base. Wells that have the potential to produce large amounts of sour gas, or are located near centres of population, now are classified as "critical" sour wells. The rules for drilling these wells have been substantially strengthened. Other potentially sour wells may not be classified as "critical", but still may require detailed emergency response plans.

Thirty-one of the 8,763 wells licensed by the ERCB in 1985 were classified as "critical". An additional 99 sour wells required emergency response plans. All applications for "critical" wells receive very detailed scrutiny from ERCB staff. There are special requirements for blowout preventers and sour-specification drilling equipment, and special training and certification is required for the drilling crews. Emergency back-up and safety precautions minimize the chances of an uncontrolled flow, as well as protecting the health of people in the unlikely event of a sour gas blowout or leak.

Emergency response plans detail the actions to be taken in the event of a "kick", or similar incident in the well, that could lead to a blowout. Detailed evacuation plans also are included, as well as lists of government and industry personnel who would be called out in the event of an emergency.

The ERCB, Alberta Public Safety Services and other government departments, also prepared an emergency response plan to coordinate the Alberta Government's response to any sour gas emergency. This plan outlines the responsibilities of all parties that would respond to an emergency and includes provisions for setting up a fully equipped command post near any emergency site, as well as an information centre to coordinate the flow of related information to and from the public and the media. A public review of the emergency response plan was carried out in 1985 through public forums in seven centres in Alberta. The plan currently is being updated as a result of these forums.

The way in which a sour gas blowout or small leak is handled also has changed dramatically since Lodgepole. An uncontrolled flow of hydrogen sulphide, of the magnitude of the 1982 Lodgepole incident, would not be permitted today. The practice would now be to ignite the gas. For example, the 1985 licence for Canadian Superior's sour gas well near Hinton specified that any uncontrolled flow of sour gas would have to be ignited immediately. Even a small leak at the well would have to be ignited, unless the ERCB permitted a short delay for repairs, and then only if there was no risk to human health.

In addition to the obvious importance of emergency planning, the major emphasis of both industry and the ERCB has been on preventing sour gas emergencies. Tougher, more frequent ERCB inspections have been imposed on sour gas drilling rigs. All "critical" wells are now inspected several times during drilling operations. Based on the new standards, none of the rigs inspected in 1985, while drilling "critical" sour wells, had serious deficiencies, compared to 11% in 1984. Rigs found to be unsafe are ordered by the ERCB to shut down until the problems are corrected.

The Blowout Prevention Review Committee (BPRC), established in 1984 by the ERCB, with representatives of government, industry and the public serving on it, is making a detailed technical and economic review of matters related to blowouts and their prevention. Several new regulations, recommended by the BPRC and adopted by the ERCB, provide tougher standards for the equipment and drilling-crew qualifications used on "critical" sour wells. The BPRC also has developed "Alberta Recommended Practices" setting high standards, approved by the ERCB and the sour gas industry, while still allowing some flexibility in engineering judgement during drilling operations.

Much progress has been made in Alberta to reduce the chances of a sour gas leak or blowout and to minimize the effects of any such incident should one occur. Improvements to equipment, procedures and crew training will continue to be made. Indeed, the Alberta Government and the energy industry already are committed to a new, multi-million-dollar facility for training drilling personnel in blowout prevention. This facility will be the most advanced of its kind in North America. Construction is expected to be completed by the end of 1986.

Hi-tech comes to the Alberta oil patch. Canterra Energy Limited used a computerized drilling rig on its sour gas well near Sundre.

Closing Stats for '85

...final figures for 1985

Because final 1985 data was not available until late in the first quarter of 1986, we held one page open until press time. The key statistics shown below are the latest figures we have available.

Wells Drilled

Exploration Wells - Oil and Gas	2,334
Development Wells - Oil and Gas	4,097
Oil Sands Wells	1,095
Total Wells Drilled	7,526

Production

	Imperial Units	Metric Units
Additions to Gas Reserves	2.1 Tcf	59 $10^9 m^3$
Gas Production	2.6 Tcf	74 $10^9 m^3$
Decrease in Remaining Reserves	0.5 Tcf	15 $10^9 m^3$
Additions to Oil Reserves	296 10^6 bbls	47.0 $10^6 m^3$
Oil Production	361 10^6 bbls	57.3 $10^6 m^3$
Decrease in Remaining Reserves	65 10^6 bbls	10.3 $10^6 m^3$
Bitumen Production	16.8 10^6 bbls	2.7 $10^6 m^3$
Synthetic Oil Production	61.4 10^6 bbls	9.8 $10^6 m^3$
Natural Gas Liquids* Production	89.2 10^6 bbls	14.2 $10^6 m^3$
Sulphur Production	5.4 10^6 LT	5.4 10^6 tonnes

* excludes pentanes plus

	Imperial Units	Metric Units
Additions to Coal Reserves	550 10^6 LT	560 10^6 tonnes
Coal Production	27 10^6 LT	28 10^6 tonnes
Increase in Remaining Reserves	523 10^6 LT	532 10^6 tonnes
Electric Generating Capacity		6.2 GW
Electricity Generated		30.2 Th

Sales

	Imperial Units	Metric Units
Oil Sales in Alberta*	107 10^6 bbls	17.1 $10^6 m^3$
Oil Sales in Other Provinces	240 10^6 bbls	38.1 $10^6 m^3$
Oil Exports	125 10^6 bbls	19.8 $10^6 m^3$

* includes conventional oil, synthetic oil, bitumen and pentanes plus

	Imperial Units	Metric Units
Gas Sales in Alberta	571 bcf	16.1 $10^6 m^3$
Gas Sales in Other Provinces	1,031 bcf	29.0 $10^6 m^3$
Gas Exports	849 bcf	23.9 $10^6 m^3$
Sulphur Sales in Alberta	457 10^3 LT	464 10^3 tonnes
Sulphur Sales in Other Provinces	268 10^3 LT	272 10^3 tonnes
Sulphur Exports	7,713 10^3 LT	7,838 10^3 tonnes
Coal Sales in Alberta	17.6 10^6 LT	17.9 10^6 tonnes
Coal Sales in Other Provinces	1.4 10^6 LT	1.4 10^6 tonnes
Coal Exports	5.3 10^6 LT	5.4 10^6 tonnes
Electrical Energy Sales		30.4 Th

ERCB Senior Management — December 31, 1985

Board Members

V. Millard	Chairman
G.J. DeSorcy	Vice Chairman
L.A. Bellows	
V.E. Bohme	
C.J. Goodman	
N. Strom	

Senior Advisors

G.A. Warne	Technical Assistant to the Board
J. Bales	Communications Advisor

Managers	**Department**
K.W. Fuller	Administrative and Financial Services
R.G. Paterson	Coal
H. Antonio	Data Processing
E.J. Morin	Development
F.J. Mink	Economics
R.F. Braun	Employee Relations
E.R. Brushett	Environment Protection
H.J. Webber	Gas
J.R. Pow	Geology
T.F. Homeniuk	Hydro and Electric
M.J. Bruni	Legal
J.A. Bray	Oil
R.G. Evans	Oil Sands
E.G. Fox	Pipeline

Acknowledgements

The Board wishes to acknowledge the valued counsel of Mel Stowko, Jack Bales, Barry Scott and Walter Casselman in preparing this report.

Additional information on the ERCB and its activities can be obtained from:

1. Information Services
   297-8190 or 297-8323

A publications catalogue is available free of charge.

2. ERCB Library
   297-7308

3. Communications Group
   297-3596

All three are located in the ERCB Head Office,
at 640 - 5th Avenue, S.W., Calgary, Alberta
T2P 3G4.

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